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BEFORE THE ARIZONA CORPORATION COMMISSION

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JEFF HATCH-MILLER, Chairman
WILLIAM A. MUNDELL
MIKE GLEASON
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BARRY WONG

AZ CORP COMMISSION
DOCUMENT CONTROL

IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR A HEARING TO DETERMINE THE FAIR VALUE OF THE UTILITY PROPERTY OF THE COMPANY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON, TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN, AND TO AMEND DECISION NO. 67744.	DOCKET NO. E-01345A-05-0816
IN THE MATTER OF THE INQUIRY INTO THE FREQUENCY OF UNPLANNED OUTAGES DURING 2005 AT PALO VERDE NUCLEAR GENERATING STATION, THE CAUSES OF THE OUTAGES, THE PROCUREMENT OF REPLACEMENT POWER AND THE IMPACT OF THE OUTAGES ON ARIZONA PUBLIC SERVICE COMPANY'S CUSTOMERS.	DOCKET NO. E-01345A-05-0826
IN THE MATTER OF THE AUDIT OF THE FUEL AND PURCHASED POWER PRACTICES AND COSTS OF THE ARIZONA PUBLIC SERVICE COMPANY.	DOCKET NO. E-01345A-05-0827

STAFF'S NOTICE OF FILING

Staff of the Arizona Corporation Commission hereby provides notice of filing the Supplemental Testimonies of John Antonuk and Randall Vickroy and the Power Supply Adjustment Plan of Administration in the above-referenced matter.

RESPECTFULLY SUBMITTED this 20th day of November, 2006.

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Arizona Corporation Commission
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BEFORE THE ARIZONA CORPORATION COMMISSION

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JEFF HATCH-MILLER, Chairman
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IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR A HEARING TO DETERMINE THE FAIR VALUE OF THE UTILITY PROPERTY OF THE COMPANY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON, TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN, AND TO AMEND DECISION NO. 57744.	DOCKET NO. E-01345A-05-0816

SUPPLEMENTAL TESTIMONY OF

JOHN ANTONUK
President, The Liberty Consulting Group

I. Introduction

Q. Mr. Antonuk, did you previously file testimony in these proceedings?

A. Yes, I filed Direct and Surebuttal Testimony addressing APS's fuel and purchased-power costs and the design of a revised PSA to recover those costs on a going-forward basis.

Q. What is the purpose of this supplemental testimony?

A. The purpose of this testimony is to address three matters, which are:

- To provide a proposed plan of administration that would implement Staff's proposed PSA mechanism, which my earlier testimony has discussed; this plan corrects a number of problems in the Rumolo rebuttal testimony's plan intended to implement Staff's proposed mechanism
- To provide the results of our review of the Company's forecast of its fuel and purchased-power costs in 2007 (based on data available as of September 29, 2006; hereafter termed the APS "Rejoinder Forecast") provided in the Rejoinder Testimony of Mr. Ewen
- To comment on the implementation of a 24-month rolling average approach to resetting a PSA rate.

Q. Was this testimony prepared by you or under your supervision?

A. Yes. In particular, I was actively involved in both the preparation and the supervision of the work on the development of the plan of administration for Staff's proposed PSA mechanism. Randall Vickroy, whose testimony accompanies mine, was the Liberty team member responsible for leading the detailed reviews underlying the portions of this testimony that address the various estimates and forecasts of fuel and purchased power costs. That work took place under my supervision, but he is much more familiar with the details underlying those estimates. His testimony accompanies mine in order to permit those parties interested in those details to pursue them with the person who is most knowledgeable about them.

2. PSA Plan of Administration

Q. Have you prepared a proposed plan of administration for implementing staff's proposed PSA?

A. Yes. That Plan of Administration ("POA") is attached as Attachment JA-1 to this testimony.

Q. Please describe the POA's implementation of the PSA.

A. The POA addresses the three components that make up the Staff's proposed PSA rate:

- A "Forward Component" to recover or refund the difference between APS's estimated fuel and purchase power costs and those embedded in base rates
- An "Historical Component" to recover or refund the difference between collections under: (1) the Forward Component plus base rates, and (2) actual fuel and purchased power costs
- A "Transition Component" to recover or refund accrued balances remaining from the prior PSA and to allow for a mid-year PSA rate adjustment to address extreme fluctuations in the marketplace.

Q. Please describe the operation of the Forward Component.

A. Staff's proposed PSA mechanism will reset the PSA rate as of February 1 each year. The POA terms this 12-month period starting on February 1 as the "PSA Year." The Forward Component of the new PSA mechanism will provide for the recovery over the coming PSA Year of the difference between the amount of fuel and purchased-power costs embedded in base rates and the amount that APS forecasts that it will incur for fuel and purchased power (assuming forecasted sales for that same period) over the calendar year (January 1 through December 31). The forecasted year is based upon a calendar year instead of the PSA Year (the PSA Year is the 12-month period staring on February 1st).

Q. Why do you use different 12-month periods for the forecast year and the PSA Year?

A. Using forecasted costs and sales will provide for more current cost recovery, but requires care in assuring that the costs and sales forecasts used to set the Forward Component have been scrutinized. Providing an adequate period for Commission review necessarily creates some time gap between the timing of the forecast and the beginning of collections based on using that forecast. The following factors guided our decision to select a calendar year forecast and a February 1 PSA Year:

- Allowing a prior opportunity for interested-party comment on and Commission review of a forecast and the new Forward Component rate calculations that depend on it
- Keeping the "vintage" of the forecast as close as feasible to the effective date of the new Forward Component's inclusion in the PSA rate customers pay

- Recognizing that calendar years would provide the most recognizable and easily implemented basis for forecasting costs and sales
- Keeping the effective date of PSA rate changes consistent with a February 1 reset date.

Q. Won't the use of different periods frustrate the ability to reconcile charges based on forecasted costs with costs actually experienced by APS?

A. No. Let me first note that providing for such reconciliation is an essential element of our proposal. We have provided a feature (the Historical Component) that will produce such reconciliation. We designed its application to provide for regular reconciliation between: (a) actual revenues collected under the Forward Component plus base rates for a given period, and (b) actual costs for the same period, in order to avoid the mismatch postulated by the question.

Q. How will this Historical Component operate?

A. Beginning with the February 1, 2008 PSA Year, the PSA will include the Historical Component. Over the course of any given PSA Year, the Forward Component Tracking Account will track collections against actual costs. These accrued balances will then be refunded or collected over the coming PSA Year. For example, the Historical Component for the PSA Year beginning February 1, 2008 will refund/recover the balance of the Forward Component Tracking Account for the prior PSA Year, *i.e.*, the PSA Year beginning February 1, 2007.

Q. Does your POA require that the first PSA Year begin on February 1, 2007?

A. No. Staff's proposed PSA recognizes the possibility that the Commission decision on whether to change the current PSA may not come in time for a new PSA Year to start on this date. We allow for that possibility by creating a first PSA Year that may have a duration of less than 12 months. We do so by fixing the first Year's end-date at January 31, 2008. This approach will allow the first PSA Year to start after February 1, 2007 without disrupting the normal cycle we anticipate for the future.

Q. How does your plan address the timing of the filings that will be required to make the Forward Component and the Historical Component operate effectively?

A. We call for the filing of the Forward Component and the Historical Component calculations to take place annually, each September 30. Using this date requires an estimate of balances for the remaining five months of the PSA Year. For example, the September 30, 2008 filing will include proposed calculations for the PSA Year starting on February 1, 2009. The September 30, 2008 filing will use actual balances accrued for the months of February through August (the first seven months of the PSA Year) and estimates of those balances for the remaining five months.

The POA requires yearly filings on September 30th with a portion to be estimated so that Staff and other interested parties can become familiar with and inquire about: (a) the forecasts used to calculate the Forward Component that will be reset in February and (b) the details underlying the calculation of the balances accruing in the Forward Component Tracking Account.

Allowing early examination of these components, balances, and calculations is important to assuring that the Commission will have an opportunity for effective review before a changed PSA rate becomes effective. We recognize, however, that the earlier we mandate the APS filing, the more we require the use of estimated versus actual data. The longer that gap becomes, the greater becomes the potential for mismatching costs and collections. Therefore, the POA provides for a second APS filing by December 31. This filing will update the estimated balance calculations and recompute the resulting Historical Component calculation.

Q. The third PSA component that Staff proposes is the Transition Component. Please describe its operation.

A. When the new PSA begins operation sometime in early 2007, there will remain balances under the PSA that applies now (the "old PSA"). The recovery of some of those balances has already been addressed by the Commission; the recovery of others, I understand, has not. The Transition Component provides a means for incorporating those specific recovery elements already approved by the Commission and for recovering any other old PSA balances that the Commission may approve.

Please understand, however, that the Staff's proposal intends no changes in the amounts of recovery of any balances accruing under the old PSA. It just provides the vehicle for recovering those already addressed by the Commission and those that may be addressed in the future.

The Transition Component also allows an opportunity for the Commission to consider whether, after the adoption of the Forward Component for any year, any changes have occurred that cause the Component to not sufficiently reflect current APS fuel and purchased-power costs. We would not expect this aspect of the Transition Component to be used frequently, if ever. We incorporated it, however, because the volatility of energy markets gives any adjustment mechanism (whether it uses partly forward/partly historic or strictly historic costs) the potential for producing recovery that far exceeds or under-runs actual costs.

The POA also recognizes that the balance established for recovery under the Transition Component may (as is the case for the Historical Component) get over or under recovered during a PSA Year. This may happen, for example, because forecasted sales used to set the rate component to recover a fixed balance will almost certainly deviate from actual sales over that period. The Transition Component will use tracking accounts to keep track of the difference between collections and balances for Commission consideration of future reconciliation. The filing of the Transition Component balances and calculations also works similarly to and under the same deadlines as those applicable to the Historical Component.

Q. Does the Staff's PSA contemplate that each new PSA Year will bring fully contested rate hearings?

A. No. We certainly consider scrutiny and an opportunity for prior Commission modification of proposed PSA components rates to be important. However, we must remember that all of the components will be reconciled to actual costs. Moreover, periodic examinations of accounting accuracy and fuel and purchased-power prudence will remain as options for adjustments as well. We believe that those protections are substantial enough to allow for a much more streamlined review before the various PSA components become effective.

We would not propose this method if it involved on a yearly basis the kind of review and time given to fuel and purchased-power issues in this proceeding. That approach would defeat the purpose of providing for an efficient means for current recovery of costs, and later review of their accounting accuracy and prudence.

3. Rejoinder Forecast Review

Q. Please describe the knowledge that Liberty's team brought to its review of the Rejoinder Forecast.

A. We began with knowledge about APS's power plants, power-purchase contracts and fuel management arrangements for calendar 2005 and into early 2006. We gained that knowledge from our audit of APS's fuels management policies and practices. In addition, we have through our work in this docket already examined a number of other similar estimates. Specifically, we began our review of the Rejoinder Forecast by examining its relationship to three estimates already available to us. John Antonuk's earlier Direct and

Surebuttal testimonies address Liberty's analysis, review, and conclusions about those three sets of information, which we describe below.

First, we examined the normalized estimate of 2006 fuel and purchased-power costs that APS witness Ewen presented in this docket in January of this year (the APS "Direct Normalized 2006 Estimate"). ***Second***, we asked that APS prepare a revised estimate of its normalized 2006 fuel and purchased-power expenses ("the Renormalized 2006 Estimate"). That estimate annualized a number of significant cost factors (*e.g.*, numbers of customers) and it normalized other factors (*e.g.*, weather, generating station maintenance schedules). That APS estimate also used actual prices that the Company had paid for fuel (including fuel transportation) and purchased power during the first six months of 2006, and forward prices for fuel and purchased power for the last six months, as those prices had been observed and reported on June 30, 2006. We used the Renormalized 2006 Estimate to form Staff's recommendation for establishing the fuel and purchased-power component of base rates. ***Third***, we asked APS to prepare a fuel-cost estimate for 2007, using similar assumptions and adjustments ("the June Vintage 2007 Estimate"). The Direct Testimony of John Antonuk commented on the June Vintage 2007 estimate to illustrate the potential impact of the very different prices for natural gas and purchased power that were present in futures prices at that time.

Q. Describe how the basis of that APS June Vintage 2007 Estimate relates to the basis on which the Staff proposes to calculate PSA rates.

A. It materially differs in two ways. First, as the Direct and Surebuttal Testimony of John Antonuk stated, the PSA mechanism that we recommend should use the best available forecasts of fuel prices and fuel requirements. The very high level of volatility that has come to characterize fuel markets requires the use of a very recent forecast to set a PSA adjustment that is forward-looking. Specifically, a forecast used for setting a forward-looking PSA should have a vintage as near as possible to the time that a PSA rate adjustment becomes effective. Assuming the continued resetting of the PSA rate each February, the end of September of the prior year is, in our judgment, about as late as an estimate can be made, while still allowing the Commission an opportunity for review before use in resetting a PSA rate.

The June Vintage 2007 Estimate, while useful in providing a comparison of 2006 and 2007 fuel costs current at that time, is not sufficiently current to use to set a 2007 PSA rate under the mechanism proposed by Staff. Moreover, the June Vintage 2007 Estimate does not comprise the kind of forecast that should be used to set a PSA rate. At the time of John Antonuk's Direct Testimony, we sought an estimate of 2007 costs that would provide an "apples-to-apples" comparison to the APS numbers underlying our proposed base rate fuel and purchased-power element. Therefore, the 2007 data that APS used in making the June Vintage 2007 Estimate used annualizations and normalizations similar to those that we asked APS to use in the Renormalized 2006 Estimate that we sought for purposes of setting base rates.

Q. Why do you believe that annualization and normalization differ in their applicability to base rates, as opposed to an adjustment clause?

A. Using annualization and normalization is generally appropriate for setting base rates, which will apply across an indefinite future period. When rates apply for a multi-year period, it is appropriate to adjust for factors that would make the use of any particular year's projections unrepresentative. For example, a unit with an 18-month outage cycle will have two outages across three years. If one of those outages occurs in the year used to set base rates, customers will in effect pay the costs of an outage every year. Certainly, an automatic recovery mechanism, such as the PSA, can correct for that mismatch; we believe, however, that good practice calls for setting base rates on the basis of properly normalized and annualized data. One exception to this general guideline, which we do not believe is material here, is that we did not normalize for contract changes that were expected to occur during or after 2006, because we felt that the PSA mechanism would provide an adequate means for testing those changes.

A PSA, however, should use forecasted costs for the single year for which it would apply, in order to avoid unnecessary complexity and to minimize the difference between the estimates used to set a PSA and actual costs. The fact that the June Vintage 2007 Estimate does not comprise a true forecast of 2007 costs forms a second reason why it would not serve well as a basis for a 2007 PSA rate.

Q. Your earlier testimony also noted the need for review of a forecast before its use to set PSA rates; have you had a chance to perform such a review of the APS Rejoinder Forecast?

A. Yes. We compared that forecast to the earlier sets of information I discussed above. We then asked APS to explain certain changes that we observed when making those comparisons. APS responded by performing a sequence of forecast runs ("cases"), with each one changing selected inputs one at a time. This sequential approach allowed us to isolate the effects of a number of significant cost changes that we had observed. We examined each of those cases, and then reviewed details of the results with APS. The purpose of these reviews was to assure ourselves that no evident errors had occurred, and that the Rejoinder Forecast displayed internal consistency.

We performed another important validation, which consisted of examining selected key elements of the underlying estimate data (*e.g.*, heat rates and fuel and transportation costs), in order to verify that those inputs either had not changed, or had changed in demonstrably valid ways, when compared with: (a) the inputs used in the other estimates we had reviewed earlier, and (b) the data we gathered during the audit.

Q. Please list and describe any important conceptual differences between APS's June Vintage 2007 Estimate and the Ewen Rejoinder Forecast.

A. The first important conceptual difference from the June Vintage 2007 Estimate is that APS's later data has included previously omitted option premium payments and large block purchases of power. Specifically, the June Vintage 2007 Estimate did not include the Rejoinder Forecast's additional option premium payments of over $30 million and additional term purchases of about 1,800 gigawatt hours, which have a forecasted cost of an additional $107.8 million. These changes produced a shift in the forecasted operation of the APS system; *i.e.*, they replaced a portion of APS's generation from new combined-cycle plants (*i.e.* Redhawk) with purchases under term contracts and tolling agreements. The changes in the operation of the APS system also caused a decrease in off-system sales, which had the effect of lowering the total margins those sales produce.

A second important difference resulted from the effects of fuel market volatility. It demonstrates how quickly costs can change. Western U.S. energy markets experienced considerable declines in fuel and purchased-power prices following the end of June. The timing of the Renormalized 2006 Estimate and the June Vintage 2007 Estimate did not permit them to reflect those declines. The Rejoinder Forecast does, however, reflect changes in the market through September of 2006. We might have seen prices go in the other direction and they may do so as the remainder of this year unfolds. They may move substantially and in unpredictable directions during 2007 as well.

Other differences between the June Vintage 2007 Estimate and the Rejoinder Forecast include:

- The Rejoinder Forecast assumes that 2007 customer additions will occur gradually throughout the course of the year; the annualized data of the previous estimates used the anticipated number of customers at year end.

- The Rejoinder Forecast used the Company's planned maintenance schedule for 2007; the previous estimates normalized outage rates across a number of years (reflecting the fact that normalizing maintenance schedules produces unit outage rates that differ from year to year within each station's particular maintenance cycle).
- APS adjusted the forecast of supplemental sales under its contracts with PacifiCorp, in order to conform them to recent experience.

The June Vintage 2007 Estimate that APS prepared for us already included some differences in assumptions from those that the Company used in its earlier estimates. Those differences resulted largely from our requested changes associated with the Renormalized 2006 Estimate.

Q. Summarize your opinion about the propriety of the APS changes from the use of annualized and normalized data in earlier estimates to the use of forecasted data in the Rejoinder Estimate.

A. We concluded from our review that the changes observed in the Rejoinder Estimate appropriately reflect forecasted 2007 costs, as opposed to normalized 2007 costs. The changes to a true "forecast" give the Rejoinder Estimate a sound conceptual base for use in setting the forward component of the PSA rate for 2007 collection.

Q. Describe what you did to examine the support for and the propriety of the changes from the June Vintage 2007 Estimate to the Rejoinder Forecast.

A. We initially discussed these changes with Mr. Ewen in a conference call. Our objective was to understand why fuel and purchased-power costs changed from the June Vintage 2007 Estimate to the Rejoinder Estimate. Following our discussion, APS developed four intermediate forecast cases. Their addition gave us six altogether. One of those six was the June Vintage 2007 Estimate. Sequentially examining the four new cases allows for the isolation of the effects of each factor that had a significant impact on the cost changes between the June Vintage 2007 Estimate and the Rejoinder Forecast (the sixth case).

Q. List the biggest factors that caused a change in net retail fuel cost from the earlier estimate.

A. The table attached to this testimony provides a comparison among the six cases. The Renormalized 2006 Estimate, which the Antonuk Direct Testimony recommended as the basis for determining the fuel cost component of the Base Rate, is also included in the table for comparison.

Our comparison of the Rejoinder Forecast and the June Vintage 2007 Estimate showed a net retail fuel cost change from \$981.7 million to \$957.7 million; *i.e.*, the Rejoinder Forecast produced a decrease of about \$24 million. This amount was noted in John Antonuk's Direct Testimony. As noted in that testimony, this amount retained the Company's proposal to retain 10 percent of the value of the fuel-cost hedges. The Rejoinder Forecast eliminated that sharing by including the fuel-cost hedges in at 100 percent. With 100 percent of the hedge values, the June Vintage 2007 Estimate was \$975.0 million. The major factors that caused the fuel cost changes between these estimates were added cumulatively from new Cases A to E, with Case E representing the estimate included in the Rejoinder Forecast. The differences in those cases consist of:

- Case A added contracted option premium payments of around $33.7 million.
- Case B changed the annualization of APS customer totals at year-end 2007 to the actual budget forecast for customers, thus decreasing load requirements.
- Case C decreased market prices for delivered natural gas by about $1.20 per Mcf and decreased power prices at Palo Verde by about $8.70 per megawatt hour on-peak and by about $9.45 per megawatt hour off-peak.
- Case D changed the modeling of the PacifiCorp Supplemental contract to more accurately reflect the company's historical experience.
- Case E included APS's 2007 plant maintenance forecast in place of a normalized maintenance schedule; Case E also included about 1,800 gigawatts of additional block purchases of power for 2007.

Q. Describe your analysis and conclusions regarding Case A.

A. Case A changed the June Vintage 2007 Estimate by including an additional amount of premiums related to APS's contracted options to buy power from off-system providers. These options form an integral part of APS' plans to meet native load requirements. APS had mistakenly omitted them from its June Vintage 2007 Estimate. The Company has identified six contracts that included capacity charges for gas tolling and peaking capacity options. APS contracted for 1,150 Megawatts of capacity for the June through September peak season and 500 megawatts for the October through December time period.

The total cost of option premiums was $33.7 million higher in Case A. The inclusion of the additional costs for generating capacity reservations increased retail fuel costs by a like amount. Two related changes offset this increase somewhat, producing a net increase of about $25 million in retail fuel costs:

- Increased net benefits from APS gas hedges offset about $6.5 million
- Additional off-system sales margins offset approximately another $2 million.

Our review produced no reason to question the propriety of this net change.

Q. Describe your analysis and conclusions regarding Case B.

A. Case B isolated the fuel-cost impacts of changing from the use of annualized customer totals as of the end of 2007 to a forecast of customer additions spread across the year. The decrease in customers during the year caused a reduction in native load sales of about 490 gigawatt hours, caused by the lower numbers of customers postulated, particularly in earlier months of 2007. The resulting reduction in load requirements lessened APS's need for generation and power purchases. This reduction decreased natural gas costs by about $12.5 million, purchased power by about $5.5 million, and coal costs slightly. The reduction in APS production requirements also freed up more Company generation for use in making economic off-system sales. Estimated margins from such sales accordingly increased by about $5 million.

In summary, a net reduction of about $23.5 million in fuel costs resulted from the change from annualized to forecasted customer numbers. Our review produced no reason to question the propriety of this net change.

Q. Describe you analysis and conclusions regarding Case C.

A. Case C examined the effects of the decrease in market prices from roughly the end of June 2006 (the time of the June Vintage 2007 Estimate) through the end of September (the vintage of the Rejoinder Forecast). Reductions across this quarter were substantial; they amounted for example to about $1.20 per Mcf in the delivered price of natural gas, which generally fires APS's marginal generating units. Gas is also the dominant source of marginal production throughout the Southwest region; therefore, this case also caused a decline in the forecasted market price of power at the Palo Verde delivery point. Estimates of on-peak electric pricing fell by about $8.70 per megawatt-hour; and off-peak pricing decreased by about $9.45 per megawatt-hour. Estimates of on-peak electric pricing fell by about $8.70 per megawatt-hour; and off-peak pricing decreased by about $9.45 per megawatt-hour.

Together, Case C's drops in natural-gas and purchased-power prices caused APS's fuel costs to decrease by about $85 million. Almost all of this forecasted reduction came from reduced costs of running the company's combined-cycle gas turbines. However, reduced production costs naturally caused a corresponding drop in the gains APS would realize from hedges. Those decreases in hedging gains totaled about $62 million. The drop in market prices also caused a decline of about $3 million in margins from off-system sales as electric pricing, unit margins, and off-system sales all declined. The net reduction in APS fuel costs from the decreases in market prices therefore amounted to $19.7 million. Our review produced no reason to question the propriety of this net change.

Q. Describe your analysis and conclusions regarding Case D.

A. The APS Rejoinder Estimate over-rode its model's forecast of the effects of the PacificCorp Supplemental Agreement. APS made this "manual" change because it considered the results to fall outside historical experience under that agreement. APS did not find any reason to believe that 2007 will bring results outside the range of its historical experience. This APS adjustment reduced the Company's native-load energy requirements by about 367 gigawatt-hours. This reduction produced a corresponding reduction in production and purchased-power requirements and related costs of about $14.5 million. This adjustment also had the effect of increasing off-system sales margins by about $3 million, because it increased the amount of system-generated power available for off-system sales.

The cumulative effect of the two impacts related to changes to the PacifiCorp agreement was to decrease fuel costs by about $17.5 million. We have some concern about manual over-rides to model outputs, but could find no independent reason for challenging the Company's justification for doing so here. Moreover, its relatively moderate cost reduction and the fact that it is reconcilable under the PSA led us to conclude that its acceptance is justifiable in these circumstances.

Q. Describe your analysis and conclusions regarding Case E.

A. Case E introduces two major changes that cause a shift in the sources of electricity forecasted by the APS dispatch model. Case E's first change applies actual (rather than normalized) 2007 maintenance schedules for APS generating units. The actual plan for 2007 includes a longer (by 23 days) Palo Verde 3 refueling outage to accommodate a steam generator replacement. Second, Case E introduces a large volume of block power purchases in order to reflect more accurately the expected capacity plan for 2007. Specifically, Case E added block purchases totaling about 1,800 gigawatt hours to the contracted option capacity already in place.

The maintenance and purchase power changes combined to produce a shift from APS's new, combined-cycle gas generation units to: (a) gas tolling purchases made under the option contracts, and (b) block term purchases. However, while Case E produced a shift in generation sources, this shift caused only minimal changes in APS's net fuel costs. Many of the combined-cycle gas units in the desert Southwest region have production profiles and costs similar to those in the APS system. Replacing APS gas generation with outside gas generation therefore does not have a very large net fuel cost impact. Case E reduced natural gas costs because it reduced the use of APS's own generation. Resulting increases in purchased-power expenses and decreases in off-system margins offset all of this reduction.

Case E produced a net change of less than $1 million in increased costs due to this substitution of gas units. Accordingly, the 23 additional outage days at Palo Verde 3 (produced by substituting a single year's forecasted duration for a multi-year period's normalized duration) accounts for almost the full amount of the $11.7 million additional fuel expense resulting under Case E. After getting APS to re-categorize and clarify several lines of its Case E run, we were able to conclude that no reason existed to question the propriety of this net change.

Q. Please summarize the overall changes in net retail fuel cost from the June Vintage 2007 Estimate to the Rejoinder Forecast.

A. The net retail fuel cost for the June Vintage 2007 Estimate was $981.7 million. The addition of capacity option premiums under six contracts added $25 million to fuel costs. The change to APS's actual plant maintenance schedule added about $11.7 million to fuel costs. The change from annualized customer levels to forecast customer levels caused a decrease of $23.5 million. The significant drop in market prices produced a decrease of $19.7 million. Finally, APS's change in estimating the impact of the PacificCorp Supplemental contract caused a reduction in fuel costs of $17.4 million. The net effect of these changes was a decrease of approximately $24 million, to $957.7 million.

Q. Describe what review you undertook to assure that base data between the estimates (*e.g.*, fuel and transportation costs, heat rates) did not change inappropriately.

A. Liberty had the same team members who conducted our fuels management audit examine all six estimates. We also examined background information that affected all six cases, such as coal costs and the costs of coal transportation. We also verified that estimates of forward prices for natural gas and purchased power were competitive.

Q. Using coal costs as an example, please describe your efforts to validate changes in underlying data.

A. We cross-checked the coal and coal transportation price data underlying the September 2006 forecast of 2007 costs for consistency with data provided earlier for 2005 and 2006. We looked at the data separately on the following bases: station by station, total delivered price, coal price, and transportation price. We used ¢/MMBtu, and delivered tons of coal as appropriate.

Our baseline data for 2005 and 2006 came from responses to data requests from both the fuel management audit and this proceeding. We were able to conclude that the overall price changes from year to year were what we expected to see, and fell within the yearly price escalation ranges that we had already observed in earlier work. We examined Four Corners and Cholla separately. The escalation in Four Corners 2007 prices was in accord with the rates we had seen for previous years, for which we had tested 2005 and early 2006 escalation rates. We had also previously tested the propriety of 2005 and early 2006 at Cholla. The changes for 2007 are in line and we found them also to reflect a recent transportation-rate settlement. We confirmed that fuel handling and adjustments remained stable, and continued to form a very small portion of overall fuel and purchased-power cost. We also verified that the overall escalation in coal costs for 2007 is in accord with expectations, given the nature of APS's supply agreements.

Q. What do you conclude about the propriety of using the newer estimate to set a PSA rate for 2007?

A. First, we consider the change from the use of annualized and normalized data to forecasted 2007 data to be appropriate. Second, we believe that the vintage (end of September 2006) of the Rejoinder Forecast appropriately balances the need for the use of current data and assumptions with the desire to continue with a PSA rate resetting in roughly the February 1, 2007 time frame.

Third, we do not seek to convey the impression that this forecast will necessarily predict what will actually happen in 2007. No estimate could, but this one, we conclude, is comprehensive and logically structured, consistent with reasonable expectations about system assets, and reflective of market price expectations current as of its vintage. Our fourth conclusion, therefore, is that our review adequately confirms the sufficiency of the Rejoinder Forecast for use in setting our proposed PSA Future Component for a PSA Year commencing at or near February 1, 2007.

4. Use of a 24-Month Rolling Average PSA

Q. What is your view of the use of a 24-month rolling average to set PSA rates?

A. The main advantage of a "rolling average" approach is that it would smooth out the cost discontinuities produced in very volatile energy markets. We consider volatility to be the main justification for an effective rate-adjustment mechanism. Therefore, we do consider that approach to be responsive to the issue of managing volatility. On the other hand, we think it can raise two major concerns. The PSA rate would change as we understand it each month to incorporate the rolling-average process. The first concern is that this approach could actually increase deferrals. Second, very frequent rate changes, even if only moderate, can increase customer confusion and cause negative customer reactions. If that approach is adopted by the Commission, however, Staff's PSA could accommodate it with changes. Those changes would eliminate the Forward Component, and change the Historical Component Tracking Account to a 24-month balance, and require the monthly calculation of a PSA rate to recover that balance.

Q. Does this conclude your testimony?

A. Yes, it does.

Attachment JA-1 to Supplemental Testimony of John Antonuk
Comparison of Fuel Cost Cases

Parameter	Base	Case A	Case B	Case C	Case D	Case E
Prices						
- Palo Verde on-peak ($/Mwh)	74.38	74.38	74.38	65.69	65.69	65.69
- Palo Verde off-peak ($/Mwh)	55.00	55.00	55.00	45.56	45.56	45.56
- Delivered gas ($/MMBtu)	8.69	8.69	8.69	7.49	7.49	7.49
On-system prod. (Gwh)						
- Nuclear	8,811	8,811	8,811	8,811	8,811	8,578
- Coal	13,230	13,246	13,218	13,200	13,156	13,181
- Natural gas	8,811	8,794	8,426	8,294	8,021	7,139
- Purchased power	1,832	1,832	1,737	1,860	1,810	2,864
Total	32,684	32,684	32,193	32,166	31,799	31,762
Off-system prod. (Gwh)						
- Nuclear	0	0	0	0	0	0
- Coal	16	16	28	26	51	144
- Natural gas	1,826	1,826	1,865	1,773	1,841	98
- Purchased power	724	724	661	727	670	1,274
Total	2,566	2,566	2,554	2,527	2,562	1,515
Off-system avg. revenue ($/Mwh)	64.57	64.57	64.37	55.91	55.95	60.79
Off-system margins ($000)	23,879	23,999	29,030	25,834	28,690	5,749
PacifiCorp Supp. Rev. ($000)	22,549	22,548	22,549	19,689	7,258	7,258
Net Retail Fuel Cost ($000)	981,708	1,006,687	983,207	963,456	946,023	957,749
Base Fuel Rate (cents/kwh)	3.2296	3.3112	3.2824	3.2204	3.2016	3.2491

Power Supply Adjustment
Plan of Administration

Table of Contents

1. General Description

This document describes the plan for administering the Power Supply Adjustment mechanism ("PSA") approved for Arizona Public Service Company ("APS") by the Commission on xxxxx, xx, 200x in Decision No. xxxxxxxx. This PSA replaces the Power Supply Adjustment mechanism approved in Decision No. 67744 ("the old PSA"). The PSA provides for the recovery of fuel and purchased power costs from January 1, 2007 onward.

The old PSA used historical, experienced costs to set a PSA rate, and then reconciled subsequent collections thereunder to actual costs, subject to a number of guidelines and limitations. By contrast, the PSA described in this Plan of Administration ("POA") uses a forward-looking estimate of fuel and purchased power costs to set a rate that is then reconciled to actual costs experienced. This PSA also provides for a transition method for the refund or collection of balances accrued under the old PSA, prior to its replacement by this PSA. This PSA also provides a mechanism for mid-year rate adjustment in the event that conditions change sufficiently to cause extraordinarily high balances to accrue under application of this PSA.

This POA describes the application of the PSA. It assumes that the old PSA continues to apply until the Commission decision regarding the adoption of this PSA during the first quarter of 2007.

2. PSA Components

The PSA Rate will consist of three components designed to provide for the recovery of actual, prudently incurred fuel and purchased power costs. Those components are:

1. The Forward Component, which recovers or refunds differences between expected PSA Year (each February 1 through January 31 period shall constitute a PSA Year) fuel and purchased power costs and those embedded in base rates.

2. The Historical Component, which tracks the differences between the PSA Year's actual fuel and purchased power costs and those recovered through the combination of base rates and the Forward Component, and which provides for their recovery during the next PSA Year.
3. The Transition Component, which provides for:
   a. The refund or recovery of balances arising under the provisions of the old PSA, prior to its replacement by this PSA.
   b. The opportunity to seek a mid-year change in the PSA rate in cases where variances between recovery of fuel and purchased power costs under the combination of base rates and the Forward Component become so large as to warrant recovery, should the Commission first deem such an adjustment to be appropriate.
   c. The tracking of balances resulting from the application of the Transition Components, in order to provide a basis for the refund or recovery of any such balances.

The PSA Year begins on February 1 and ends on the ensuing January 31.[1] The first PSA Year in which the new PSA rate shall apply will begin on February 1, 2007 or such other date on which the Commission approves the adoption of this PSA. In any event, the first PSA Year will end on January 31, 2008. Succeeding PSA Years will begin on each February 1 thereafter.

On or before September 30 of each year, APS will submit a PSA Rate filing, which shall include a proposed calculation of the three components of the PSA Rate. This filing shall be accompanied by such supporting information as Staff determines to be required. APS will supplement this filing with Historical Component and Transition Component filings on or before December 31 in order to replace estimated balances with actual balances, as explained below.

a. Forward Component Description

The Forward Component is intended to refund or recover the difference between: (1) the fuel and purchased power costs embedded in base rates and (2) the forecasted fuel and purchased power costs over a PSA Year that begins on February 1 and ends on the ensuing January 31. APS will submit, on or before September 30 of each year, a forecast for the upcoming calendar year (January 1-December 31) of its fuel and purchased power costs. It will also submit a forecast of kWh sales for the same calendar year, and divide the forecasted costs by the forecasted sales to produce the ¢/kWh unit rate required to collect those costs over those sales. The result of subtracting the Base Cost of Fuel and Purchased Power from this unit rate shall be the Forward Component.

APS shall maintain and report monthly the balances in a Forward Component Tracking Account, which will record APS' over/under-recovery of its actual costs of fuel and purchased power as compared to the actual Base Cost of Fuel and Purchased Power revenue and Forward Component revenue. This account will operate on a PSA Year basis (*i.e.*; February to January), and its

[1] The Commission decision approving this PSA may come after February 1, 2007, in which case the first PSA Year will be less than 12 months.

balances will be used to administer this PSA's Historical Component, which is described immediately below.

b. Historical Component Description

The Historical Component in any current PSA Year is intended to refund or recover the balances accumulated in the Forward Component Tracking Account (described above) and Historical Component Tracking Account (described below) during the immediately preceding PSA Year. The sum of the Forward Component Tracking Account balance and the Historical Component Tracking Account balance is divided by the forecasted kWh sales used to set the Forward Component for the coming PSA Year. That result comprises the proposed Historical Component for the coming PSA year.

APS shall maintain and report monthly the balances in a Historical Component Tracking Account, which will reflect monthly collections under the Historical Component and the amounts approved for use in calculating the Historical Component.

Each annual September 30 APS filing will include an accumulation of Forward Component Tracking Account balances and Historical Component Tracking Account balances for the preceding February through August and an estimate of the balances for September through January (the remaining five months of the current PSA Year). The APS filing shall use these balances to calculate a preliminary Historical Component for the coming PSA Year[2]. On or before December 31, APS will submit a supplemental filing that recalculates the preliminary Historical Component. This recalculation shall replace estimated monthly balances with those actual monthly balances that have become available since the September 30 filing.

The September 30 filing's use of estimated balances for September through January (with supporting workpapers) is required to allow the PSA review process to begin in a way that will support its completion and a Commission decision prior to February 1. The December 31 updating will allow for the use of the most current balance information available prior to the time when a Commission decision is expected. In addition to the December 31 update filing, APS monthly filings (for the months of September through December) of Forward Component Tracking Account balance information and Historical Component Tracking Account balance information will include a recalculation (replacing estimated balances with actual balances as they become known) of the projected Historical Component unit rate required for the next PSA Year.[3]

The Historical Component Tracking Account will measure the changes each month in the Historical Component balance used to establish the current Historical Component as a result of collections under the Historical Component in effect. It will subtract each month's Historical Component collections from the Historical Component balance. The Historical Component

[2] For example, the September 30, 2007 filing would include actual balances for February through August of 2007 and estimated balances for September 2007 through January 2008.

[3] This updating to replace estimated with actual information will allow for the Commission to use the latest available balance information in determining what Historical Component is appropriate to establish for the coming PSA Year.

Account will also include Applicable Interest on any balances. APS shall file the amounts and supporting calculations and workpapers for this account each month.

c. Transition Component Description

As of February 1, 2007, there will remain balances under the operation of the old PSA. This PSA does not make any change in the recoverability of such balances, but does apply the Transition Component as a method for recovering such balances as are already permitted for recovery under the old PSA and whose recovery the Commission may otherwise allow. The Transition Component will provide for the capturing and collection of those balances. APS will continue to make the filings required under the old PSA for so long as is necessary to recover and reconcile any balances arising thereunder, to the extent that such balances have not been transferred for recovery through the Transition Component of this PSA. Pre-2007 balances already approved for recovery (but not already recovered) under the old PSA will be rolled into the Transition Component upon this PSA's effective date. Any 2007 balances accruing under the old PSA before its replacement will be tracked during the first PSA Year, and their recovery shall be addressed in the calculation of the Transition Component applicable during the second PSA Year, which shall begin on February 1, 2008. The pre-2007 charges already approved for recovery under the old PSA consist of the following:[4]

1. February 1, 2006, adjustor rate of $0.004 per kWh to recover $110 million of 2005 costs;
2. May 1, 2006, surcharge of $0.000554 per kWh to recover $15 million of 2005 costs outside of 4 mil bandwidth that are not related to nuclear plant outages; and
3. May 1, 2006, interim adjustor rate of $0.007 per kWh to recover certain 2006 costs as described in Decision No. 68685.

APS shall file by December 31, 2006[5] a calculation of the ¢/kWh unit rate required to collect costs included in the preceding list over the same estimate of 2007 sales used to calculate the Forward Component. This calculation shall comprise the Transition Component for the first PSA Year's PSA rate.

The Transition Component will also be used if necessary to address the need for any other reconciliations that may be required or appropriate under the old PSA. Following review, the Commission will determine the amount to be collected and the period over which it will be collected. The amount permitted to be collected shall be included in the Transition Component Balance. The Transition Component will provide the PSA element for the collection of the approved Transition Component Balance over the time period established by the Commission.

The preceding uses of the Transition Component deal with the transition from the old PSA to this PSA. The Transition Component will also be used as the method for incorporating any future, approved mid-year changes to the PSA rate. APS, Staff, or the Commission on its own motion retain the ability to request at any time a change in the PSA rate through an adjustment to the

[4] Depending upon the Commission's resolution of APS' pending rate case, Docket No. E-01345A-05-0816, APS may also be allowed to recover certain prudently incurred fuel and purchased power costs incurred as a result of certain Palo Verde outages.

[5] Staff acknowledges that the 2006 information would have to be addressed in the context of the pending rate case, Docket No. E-01345A-05-0816.

Transition Component to address a significant imbalance between collections and costs under the Forward Component element of this PSA. After the review of such request, the Commission may provide for the refund or collection of such balance (through a change to the Transition Component Balance) over such period as the Commission determines appropriate through a unit rate (¢/kWh) imposed as part of the Transition Component.

A Transition Component Tracking Account will measure the changes each month in the Transition Component balance. APS, Staff, or the Commission on its own motion may request that the balance in any Transition Component Tracking Account at the end of the period set for recovery be included in the establishment of the Transition Component for the coming PSA Year.

The Transition Component Account will also include Applicable Interest as determined by the Commission. APS shall file the amounts and supporting calculations and workpapers for this account each month.

As it must do for the Historical Component filing, APS shall file on or before September 30 of each year an accumulation of Transition Component Tracking Account balances for the preceding February through August and an estimate of the balances for September through January (the remaining five months of the prior PSA Year). Those balances will form the basis for setting the preliminary Transition Component for the coming PSA Year. On or before December 31, APS will submit a supplemental filing to update the Transition Component calculation in the same manner as required for the Historical Component.

3. Calculation of the PSA Rate

The PSA rate is the sum of the three components; *i.e.*, Forward Component, Historical Component, and Transition Component. The PSA rate shall be applied to customer bills. Unless the Commission has otherwise acted on a new PSA rate by February 1, the proposed PSA rate (as amended by the updated December 31 filing) shall go into effect. The PSA rate shall be applicable to APS' retail electric rate schedules (with the exception of Solar-1, Solar-2, SP-1, E-3, E-4, E-36, Direct Access service and any other rate that is exempt from the PSA) and is adjusted annually. The PSA Rate shall be applied to the customer's bill as a monthly kilowatt-hour ("kWh") charge that is the same for all customer classes.

The PSA rate shall be reset on February 1 of each year, and shall be effective with the first billing cycle in February unless suspended by the Commission. It is not prorated.

4. Filing and Procedural Deadlines

a. September 30 Filing

APS shall file the PSA rate with all Component calculations for the PSA year beginning on the next February 1, including all supporting data, with the Commission on or before September 30 of each year. That calculation shall use a forecast of kWh sales and of fuel and purchased power costs for the coming calendar year, with all inputs and assumptions being current as of that date for the Forward Component. The filing will also include the Historical Component calculation for the year beginning on the next February 1, with all supporting data. That calculation shall use the same forecast of sales used for the Forward Component calculation. The Transition Component filing shall also include a proposed method for addressing the over or under recovery of any Transition Component balances that result from changes in the sales forecasts or recovery periods set or any additions to or subtractions from Transition Component balances reviewed or approved by the Commission since the last February 1 resetting of the new PSA.[6]

b. December 31 Filing

APS shall by December 31 update the September 30 filing. This update shall replace estimated Forward Component Tracking Account balances, the Historical Component Tracking Account balances, and the Transition Component Tracking Account balances with actual balances and with more current estimates for those months (December and January) for which actual data are not available. Unless the Commission has otherwise acted on the APS calculation by February 1, the PSA rate proposed by APS shall go into effect on February 1, subject to true-up.

c. Additional Filings

APS shall also file with the Commission any additional information that the Staff determines it requires to verify the component calculations, account balances, and any other matter pertinent to the PSA.

d. Review Process

The Commission Staff and interested parties shall have an opportunity to review the September 30 and December 31 forecast, balances, and supporting data on which the calculations of the three PSA components have been based. Any objections to the September 30 calculations shall be filed within 45 days of the APS filing. Any objections to the December 31 calculations shall be filed within 15 days of the APS filing.

5. Verification and Audit

The amounts charged through the PSA shall be subject to periodic audit to assure their completeness and accuracy and to assure that all fuel and purchased power costs were incurred reasonably and prudently. The Commission may, after notice and opportunity for hearing, make such adjustments to existing balances or to already recovered amounts as it finds necessary to correct any accounting or calculation errors or to address any costs found to be unreasonable or imprudent. Such adjustments, with appropriate interest, shall be recovered or refunded through the Transition Component.

6. Definitions

Applicable Interest – Based on one-year Nominal Treasury Constant Maturities rate contained in the Federal Reserve Statistical Release H-15.

[6] This method assumes that the Commission defers the recovery of any approved Transition Component Balance changes until the next February 1 PSA resetting. The Commission may also, as part of the approval of any such Transition Component Balance change, make a PSA change effective on dates and across periods as it determines to be appropriate when it approves such a Transition Component Balance change.

Base Cost of Fuel and Purchased Power – An amount generally expressed as a rate per kWh, which reflects the fuel and purchased power cost embedded in the base rates as approved by the Commission in APS' most recent rate case. The Base Cost of Fuel and Purchased Power revenue is the approved rate per kWh times the applicable sales volumes. Decision No. XXXXX set the base cost at $0.0XXXXX per kWh effective on XXX, XXXX.

Forward Component – An amount generally expressed as a rate per kWh charge that is updated annually on February 1 of each year and effective with the first billing cycle in February. The purpose of the Forward Component is to adjust the cost of fuel and purchased power embedded in APS' base rates to reflect the difference between the prior calendar year's actual fuel and purchased power costs and the recovery of such costs under the combination of the base fuel rate of $0.0XXXXX per kWh and the Forward Component applicable for that prior calendar year.

Forward Component Tracking Account – An account that records on a monthly basis APS's over/under-recovery of its actual costs of fuel and purchased power as compared to the actual Base Cost of Fuel and Purchased Power revenue and Forward Component revenue; plus Applicable Interest. The balance of this account as of the end of each PSA Year is, subject to periodic audit, reflected in the next Historical Component calculation. APS files the balances and supporting details underlying this Account with the Commission on a monthly basis.

Historical Component – An amount generally expressed as a rate per kWh charge that is updated annually on February 1 of each year and effective with the first billing cycle in February unless suspended by the Commission. The purpose of this charge is to provide for a true-up mechanism to reconcile any over or under-recovered amounts from the preceding PSA Year tracking account balances to be refunded/collected from customers in the coming year's PSA rate.

Historical Component Tracking Account – An account that records on a monthly basis the account balance to be collected via the Historical Component rate as compared to the actual Historical Component revenues; plus Applicable Interest; the balance of which at the close of the preceding PSA Year is, subject to periodic audit, then reflected in the next Historical Component calculation. APS files the balances and supporting details underlying this Account with the Commission on a monthly basis.

ISFSI –Costs associated with the Independent Spent Fuel Storage Installation that stores spent nuclear fuel.

Mark-to-Market Accounting – Recording the value of qualifying commodity contracts to reflect their current market value relative to their actual cost.

Native Load – Native load includes customer load in the APS control area for which APS has a generation service obligation and PacifiCorp Supplemental Sales.

PacifiCorp Supplemental Sales – The PacifiCorp Supplemental Sales agreement is a long-term contract from 1990, which requires APS to offer a certain amount of energy to PacifiCorp each year. It is a component of the set of agreements that led to the sale of Cholla Unit 4 to PacifiCorp and the establishment of the seasonal diversity exchange with PacifiCorp.

Old PSA – The Power Supply Adjustment mechanism approved in Decision No. 67744 to track changes in the APS cost of obtaining fuel and purchased power.

This PSA – The Power Supply Adjustment mechanism approved by the Commission in Decision No. xxxxx, which is a combination of three rate components that track changes in the cost of obtaining power supplies based upon forward-looking estimates of fuel and purchased power costs that are eventually reconciled to actual costs experienced. This PSA also provides for the transition from the prior PSA to this PSA, allows for special Commission consideration of extreme volatility in costs or recovery by means of a mid-year rate correction, and provides for a reconciliation between actual and estimated costs of the last two months of estimated costs used in Historical Component calculations.

PSA Year – A consecutive 12-month period generally beginning each February 1.

PSA Year One – A period beginning on the date determined by the Commission in Decision No. xxxxx and ending on January 31, 2008.

Preference Power – Power allocated to APS wholesale customers by federal power agencies such as the Western Area Power Administration.

System Book Fuel and Purchased Power Costs – The costs recorded for the fuel and purchased power used by APS to serve both Native Load and off-system sales, less the costs associated with applicable special contracts, E-36, RCDAC-1, ISFSI, and Mark-to-Market Accounting adjustments. Wheeling costs are included; broker fees are excluded.

System Book Off-System Sales Revenue – The revenue recorded from sales made to non-Native Load customers, for the purpose of optimizing the APS system, using APS-owned or contracted generation and purchased power, less Mark-to-Market Accounting adjustments.

Traditional Sales-for-Resale – The portion of load from Native Load wholesale customers that is served by APS, excluding the load served with Preference Power.

Transition Component – An amount generally expressed as a rate per kWh charge to be applied when necessary to provide for: (a) the transition between the prior PSA and current PSA, and (b) significant changes between estimated and actual costs under the Forward Component.

Transition Component Tracking Account – An account that records on a monthly basis the account balance to be collected via the Transition Component as compared to the actual Transition Component revenues, plus applicable interest; the balance of which upon Commission consideration may then be reflected in the next Transition Component calculation. APS files the balances and supporting details underlying this Account with the Commission on a monthly basis.

Wheeling Costs (FERC Account 565, Transmission of Electricity by Others) – Amounts payable to others for the transmission of APS' electricity over transmission facilities owned by others.

7. Calculations

a. Schedule 1. PSA Rate Calculation

Enter the appropriate effective periods for the Current and Proposed PSA columns and then complete the following in each respective column:

1. On Line 1, enter the Forward Component from Schedule 2, Line 8.
2. On Line 2, enter the Historical Component from Schedule 4, Line 5.
3. On Line 4, enter the Transition Component for the Commission approved prior PSA transition refund/collection balance from Schedule 6, Line 3.
4. On Line 5, enter the Transition Component for any Commission approved Mid-Period Transition refund/collection balance from Schedule 6, Line 6.
5. On Line 6, enter the Transition Component for any other Commission approved Transition adjustment refund/collection balance from Schedule 6, line 9.
6. On Line 7, enter the Tracking Account Transition Component for any Commission approved refund/collection Tracking Account balance from Schedule 6, Line 20.
7. On Line 8, enter the sum of Lines 4 through 7 to calculate total Transition Component.
8. On Line 9, enter the sum of Lines 1, 2, and 8 to calculate the total PSA Rate.
9. Calculate the Increase/(Decrease) in rates and % Change by respective lines: Proposed Rates Less Current Rates equals Increase/(Decrease) with result divided by Current Rate to determine % of Increase/(Decrease).

Reflect notes as appropriate.

b. Schedule 2. PSA Forward Component Calculation

Enter the appropriate effective periods for the Current and Proposed PSA-2 columns and then complete the following in each respective column:

1. On line 1, enter the Projected Fuel and Purchased Power Costs for the coming year.
2. On Line 2, enter the Projected Off-System Sales Revenue (entered as a negative value) for the coming year.
3. On Line 3, enter the PSA Adjustments to Fuel and Purchased Power Costs for the coming year.
4. On Line 4, enter the sum of Lines 1 through 3 to arrive at the Net Fuel and Purchased Power Costs.
5. On Line 5, enter the Projected Native Load Sales (kWh), excluding the E-3, E-4, E-36 sales for the coming year.
6. On Line 6, enter the derivation of the Net Fuel and Purchased Power Costs divided by the Projected Native Load Sales to arrive at the Projected Average Net Fuel Cost per kWh.
7. On Line 7, enter the Authorized Base Fuel Rate per kWh.
8. On Line 8, enter the sum of Line 6 less Line 7 to arrive at the Forward Component rate per kWh; and then carry forward resultant value to Schedule 1, Line 1.

Reflect notes as appropriate.

c. Schedule 3. Forward Component Tracking Account

Enter the appropriate: effective dates for the PSA ***Prior*** Forward Component being tracked; year for the column headed "Cycle Billing Month"; and Base Rate and Forward Component in columns ***h*** and ***i***. On lines 1 through 12 under the Cycle Billing Month, January through December for each respective column complete the following:

1. On Lines 1 to 12, enter the monthly Retail Energy Sales (MWh) and the monthly Wholesale Native Load Energy Sales in columns ***a*** and ***b***, respectively; the sum which equals the Total Native Load Energy Sales; column ***c***. Currently, Wholesale Native Load Energy Sales include Traditional Sales-for-Resale and PacifiCorp Supplemental Sales.
2. On Lines 1 to 12, enter the monthly System Book Fuel and Purchased Power Costs and the monthly System Book Off-System Sales Revenue in columns ***d*** and ***e***, respectively; the sum of column ***d*** minus ***e*** equals the monthly Net Native Load Power Supply Costs in column ***f***. The off-system sales margin is embedded in the Net Native Load Power Supply Cost. The costs associated with the off-system sales are included in the System Book Fuel and Purchased Power Costs. When the System Book Off-System Sales Revenue is subtracted from the System Book Fuel and Purchased Power Costs, the difference between the off-system sales costs and revenue ends up in the Net Native Load Power Supply Cost. That difference is the off-system sales margin. A list of the items included in the PSA sales and costs described above will be included in the PSA reporting schedules filed with the Commission each month.
3. On Lines 1 to 12, calculate the PSA Retail Power Supply Costs, column ***g*** by dividing the Retail Energy Sales in column ***a*** by the Total Native Load Energy Sales in column ***c***, then multiply the product by the Net Native Load Power Supply Costs in column ***f***. Directly-assigned power supply costs and related energy sales from applicable special contract customers, Schedule E-36 customers, and customers returning to Standard Offer service from competitive generation subject to Returning Customer Direct Access Charge ("RCDAC") treatment will be deducted prior to the above calculations.
4. On Lines 1 to 12, calculate the amount recovered via the Commission approved embedded base fuel and purchased power rate by multiplying the Retail Energy Sales in column ***a*** by the Commission approved Base Cost of Fuel and Purchased Power rate entered in the above column heading the result which is entered in column ***h***.
5. On Lines 1 to 12, calculate the amount recovered via the Forward Component rate by multiplying said rate by the Retail Energy Sales in column ***a***, the result which is entered in column ***i***.
6. On lines 1 to 12, calculate the respective level of (Over)/Under Collection in column ***j*** by subtracting the Base Rate Power Supply Recovery and the Forward Component rate recovery from the PSA Retail Power Supply Costs, columns ***g*** and ***h***, respectively.

An interest rate, based on the one-year Nominal Treasury Constant Maturities rate contained in the Federal Reserve Statistical Release, H-15, is applied each month to the previous month's Tracking Account Balance. The interest rate is adjusted annually on the first business day of the calendar year in the same manner as the APS customer deposit rate.

The (Over)/Under Collection, the Interest and the prior month's Tracking Account Balance produce the current month's balance.

d. Schedule 4. PSA Historical Component Calculation

Enter the appropriate effective periods for the Current and Proposed PSA-2 columns and then complete the following in each respective column:

1. On Line 1, enter the Forward Component Tracking Account Balance from Schedule 3, L13, column ***i***.
2. On Line 2, enter the Historical Component Tracking Account Balance from Schedule 5, Line 8.
3. On Line 3, enter the sum of Lines 1, and 2 to arrive at the Total (Refundable)/Collection Amount Balance.
4. On Line 4, enter the respective Projected Energy Sales without E-3, E-4 and E-36 MWh.
5. On Line 5, enter the Applicable Historical Component rate by dividing Line 3 by Line 4.

Reflect notes as appropriate.

e. Schedule 5. Historical Component Tracking Account

Enter the appropriate: effective dates for the PSA ***Prior*** Historical Component being tracked.

On Line 8, for January and Line 1 for February, enter the Historical Component balance as of February 1, 20XX. On Line 2, (Prior period PSA Historical Component Calculation From Schedule 4, L4) for February enter any true-up for the use of prior period estimates, i.e., prior estimated December and January Historical Component rate application revenues to subsequent actual data, the sum of Lines 1 and 2, to reflect the Adjusted Historical Component Beginning Balance as of February 1, 20XX.

Each month, the Applicable Historical Component rate is multiplied by the Retail Energy Sales to calculate the revenue received from the Applicable Historical Component rate. The revenue is subtracted from the Adjusted Beginning Balance.

Interest is applied monthly based on the effective one-year Nominal Treasury Constant Maturities rate that is contained in the Federal Reserve Statistical Release, H-15, or its successor publication. The interest rate is adjusted annually on the first business day of the calendar year in the same manner as the APS customer deposit rate.

Reflect notes as appropriate.

f. Schedule 6. PSA Transition Component Calculation

Enter the appropriate effective periods for the Current and Proposed PSA columns and then complete the following in each respective column:

1. On Line 1, enter the Prior PSA Transition Commission Approved (Refundable)/Collection Amount.
2. On Line 2, enter the Projected Energy Sales without E-3, E-4, and E-36 MWh.
3. On Line 3, calculate the Prior PSA Transition Component (Refundable)/Collection Rate by dividing Line 1 by Line 2.
4. On Line 4, enter the PSA Mid-Period Transition Commission Approved (Refundable)/Collection Amount, if any.
5. On Line 5, enter the Projected Energy Sales without E-3, E-4, and E-36 MWh.
6. On Line 6, calculate the Mid-Period Transition Component (Refundable)/Collection Rate by dividing Line 4 by Line 5.
7. On Line 7, enter Any Other Transition Commission Approved (Refundable)/Collection Amount, if any.
8. On Line 8, enter the Projected Energy Sales without E-3, E-4, and E-36 MWh.
9. On Line 9, calculate the Any Other Transition Component (Refundable)/Collection Rate by dividing Line 7 by Line 8.
10. On Line 10, enter the sum of Lines 3, 6, and 9 to arrive at the total Transition Component (Non-Tracking Account Items).
11. On Line 11, enter the Prior PSA Transition Tracking Account Balance from Schedule 7a, Line 8.
12. On Line 12, enter the Projected Energy Sales without E-3, E-4, and E-36 MWh.
13. On Line 13, calculate the Prior PSA Tracking Account Transition Component (Refundable)/Collection Rate by dividing Line 11 by Line 12.
14. On Line 14, enter the Mid-Period PSA Transition Tracking Account Balance from Schedule 7b, Line 8, if any.
15. On Line 15, enter the Projected Energy Sales without E-3, E-4, and E-36 MWh.
16. On Line 16, calculate the Mid-Period Tracking Account Transition Component (Refundable)/Collection Rate by dividing Line 14 by Line 15.
17. On Line 17, enter Any Other PSA Transition Tracking Account Balance from Schedule 7X, Line 8, if any.
18. On Line 18, enter the Projected Energy Sales without E-3, E-4, and E-36 MWh.
19. On Line 19, calculate the Any Other Tracking Account Transition Component (Refundable)/Collection Rate by dividing Line 17 by Line 18.
20. On Line 20, calculate the total Tracking Account Transition Component by adding Lines 13, 16, and 19.
21. On Line 21, calculate the total Transition Component by adding Lines 10 and 20.

Reflect notes as appropriate.

g. Schedule 7a. Transition Component Tracking Account "Old PSA"

Enter the appropriate: effective dates for the PSA ***Prior*** Transition Component to be tracked.

On Line 8, for January and Line 1 for February, enter the Transition Component, Old PSA balance as of February 1, 20XX. On Line 2, (Prior period PSA Transition Component Calculation From Schedule 6, L1) for February enter any true-up for the use of prior period estimates, i.e., prior estimated December and January Transition Component, Old PSA application revenues to subsequent actual data, the sum of Lines 1 and 2, to reflect the Transition Component Adjusted Beginning Balance as of February 1, 20XX.

Each month, the Applicable Transition Component rate is multiplied by the Retail Energy Sales to calculate the revenue received from the Applicable Transition Component rate. The revenue is subtracted from the Adjusted Beginning Balance.

Interest is applied monthly based on the effective one-year Nominal Treasury Constant Maturities rate that is contained in the Federal Reserve Statistical Release, H-15, or its successor publication. The interest rate is adjusted annually on the first business day of the calendar year in the same manner as the APS customer deposit rate.

Any subsequent balanced produced must be approved by the Commission for later inclusion in the next Transition Component Calculation, if any, at Schedule 6, Line 11.

Reflect notes as appropriate.

h. Schedule 7b. Mid-Point Transition Tracking Account

Enter the appropriate: effective dates for the PSA ***Mid-Point*** Transition Component to be tracked.

On Line 8, for January and Line 1 for February, enter the Transition Component, PSA Mid-Point balance as of February 1, 20XX. On Line 2, (Prior period PSA Transition Component Calculation From Schedule 6, L4) for February enter any true-up for the use of prior period estimates, i.e., prior estimated December and January Transition Component rate application revenues to subsequent actual data, the sum of Lines 1 and 2, to reflect the Adjusted Transition Component Beginning Balance as of February 1, 20XX.

Each month, the Applicable Transition Component rate is multiplied by the Retail Energy Sales to calculate the revenue received from the Applicable Transition Component rate. The revenue is subtracted from the Adjusted Beginning Balance.

Interest is applied monthly based on the effective one-year Nominal Treasury Constant Maturities rate that is contained in the Federal Reserve Statistical Release, H-15, or its successor publication. The interest rate is adjusted annually on the first business day of the calendar year in the same manner as the APS customer deposit rate.

Any subsequent balance produced must be approved by the Commission for later inclusion in the next Transition Component Calculation, if any, at Schedule 6, Line 14.

Reflect notes as appropriate.

i. Schedule 7X. (Enter Description) Transition Tracking Account

Follow similar procedures discussed in g and h above, for any other Transition Tracking Accounts.

8. Compliance Reports

APS shall provide monthly reports to Staff's Compliance Section and to the Residential Utility Consumer Office detailing all calculations related to the PSA. An APS Officer shall certify under oath that all information provided in the reports itemized below is true and accurate to the best of his or her information and belief. These monthly reports shall be due within 30 days of the end of the reporting period.

The publicly available reports will include at a minimum:

1. The PSA Rate Calculation (Schedule 1); Forward Component, Historical Component, and Transition Component Calculations (Schedules 2, 4, and 6); Annual Forward Component, Historical Component, and Transition Component Tracking Account Balances (Schedules 3, 5, and 7). Additional information will provide other relative inputs and outputs such as:
    a. Total power and fuel costs.
    b. Customer sales in both MWh and thousands of dollars by customer class.
    c. Number of customers by customer class.
    d. A detailed listing of all items excluded from the PSA calculations.
    e. A detailed listing of any adjustments to the adjustor reports.
    f. Total off-system sales revenues.
    g. System losses in MW and MWh.
    h. Monthly maximum retail demand in MW.

2. Identification of a contact person and phone number from APS for questions.

APS shall provide to Commission Staff monthly reports containing the information listed below. These reports shall be due within 30 days of the end of the reporting period. All of these additional reports will be provided confidentially.

A. Information for each generating unit shall include the following items:
1. Net generation, in MWh per month, and 12 months cumulatively.
2. Average heat rate, both monthly and 12-month average.
3. Equivalent forced-outage rate, both monthly and 12-month average.
4. Outage information for each month including, but not limited to, event type, start date and time, end date and time, and a description.
5. Total fuel costs per month.
6. The fuel cost per kWh per month.

B. Information on power purchases shall include the following items per seller (information on economy interchange purchases may be aggregated):
1. The quantity purchased in MWh.
2. The demand purchased in MW to the extent specified in the contract.

3. The total cost for demand to the extent specified in the contract.
4. The total cost of energy.

C. Information on off-system sales shall include the following items:
1. An itemization of off-system sales margins per buyer.
2. Details on negative off-system sales margins.

D. Fuel purchase information shall include the following items:
1. Natural gas interstate pipeline costs, itemized by pipeline and by individual cost components, such as reservation charge, usage, surcharges and fuel.
2. Natural gas commodity costs, categorized by short-term purchases (one month or less) and longer term purchases, including price per therm, total cost, supply basin, and volume by contract.

E. APS will also provide:
1. Monthly projections for the next 12-month period showing estimated (Over)/under-collected amounts.
2. A summary of unplanned outage costs by resource type.
3. The data necessary to arrive at the System and Off-System Book Fuel and Purchased Power cost reflected in the non-confidential filing.
4. The data necessary to arrive at the Native Load Energy Sales MWh reflected in the non-confidential filing.

Work papers and other documents that contain proprietary or confidential information will be provided to the Commission Staff under an appropriate confidentiality agreement. APS will keep fuel and purchased power invoices and contracts available for Commission review. The Commission has the right to review the prudence of fuel and power purchases and any calculations associated with the PSA at any time. Any costs flowed through the PSA are subject to refund, if those costs are found to be imprudently incurred.

9. Allowable Costs

a. Accounts

The allowable PSA costs include fuel and purchased power costs incurred to provide service to retail customers. Additionally, the prudent direct costs of contracts used for hedging system fuel and purchased power will be recovered under the PSA. The allowable cost components include the following Federal Energy Regulatory Commission ("FERC") accounts:

- 501 Fuel (Steam)
- 518 Fuel (Nuclear) less ISFSI regulatory amortization
- 547 Fuel (Other Production)
- 555 Purchased Power
- 565 Wheeling (Transmission of Electricity by Others)

These accounts are subject to change if the Federal Energy Regulatory Commission alters its accounting requirements or definitions.

b. Directly Assignable Power Supply Costs Excluded

Decision No. 66567 provides APS the ability to recover reasonable and prudent costs associated with customers who have left APS standard offer service, including special contract rates, for a competitive generation supplier and then return to standard offer service. For administrative purposes, customers who were direct access customers since origination of service and request standard offer service would be considered to be returning customers. A direct assignment or special adjustment may be applied that recognizes the cost differential between the power purchases needed to accommodate the returning customer and the power supply cost component of the otherwise applicable standard offer service rate. This process is described in the Returning Customer Direct Access Charge rate schedule and associated Plan for Administration filed with the Commission.

In addition, if APS purchases power under specific terms on behalf of a standard offer special contract customer, the costs of that power may be directly assigned. In both cases, where specific power supply costs are identified and directly assigned to a large returning customer or standard offer special contract customer or group of customers, these costs will be excluded from the Adjustor Rate calculations. Schedule E-36 customers are directly assigned power supply costs based on the APS system incremental cost at the time the customer is consuming power from the APS system so their power supply costs are excluded from the PSA.

SUPPLEMENTAL TESTIMONY OF

RANDALL VICKROY
The Liberty Consulting Group

Addressing the Review of APS's 2007 Fuel and Purchased Power Forecast

Q. Please state your name and business address.

A. My name is Randall Vickroy; my Liberty address is 65 Main Street, P.O. Box 1237, Quentin, Pennsylvania 17083.

Q. Please describe your background and qualifications.

A. My utility experience extends across more than 25 years, during which I have been a utility practitioner and management consultant. I have worked with Liberty on many utility consulting projects in over 20 states. My work for Liberty covers a wide range of financial and operational issues.

I received a Bachelor of Arts from Monmouth College in 1976 with a major in business administration. I received a Masters of Business Administration degree from the University of Denver with an emphasis in finance in 1978. Public Service Company of Colorado, an electric and gas utility, hired me in 1979 as a financial analyst in the corporate finance and planning department. For the next twelve years I held the positions of financial analyst, financial supervisor, director of analysis, business development manager, and assistant to the chief financial officer. My responsibilities included financial planning, capital acquisition, capital spending analysis and allocation, treasury operations, securitization financing, project financing, mergers and acquisitions, cash management, and investor relations.

I began in 1991 to consult on business, corporate finance, operations and affiliate issues in the electricity, natural gas, and telecommunications industries. I have since then provided consulting services to utility commissions and to companies in over 25 states and in three foreign countries. From 1991 through 1998 I was a senior consultant with the Liberty Consulting Group. From 1999 until 2001, I was a project manager on major utility consulting engagements for Deloitte Consulting. From 2001 until the present, I resumed consulting for Liberty.

Q. Mr. Vickroy, please describe your role on the fuel audit and on the rate case prior to APS's filing of the Rejoinder Forecast.

A. I examined power purchases and off-system sales in the audit and in this docket. I researched the questions raised by Commissioner Mundell about comparative APS off-system sales, and I reviewed all of the normalized estimates and forecasts prepared by APS in or related to this docket.

Q. What is the purpose of your testimony in these proceedings?

A. I seek to confirm and adopt the portions of Mr. Antonuk's testimony addressing the various fuel and purchased-power estimates and forecasts his testimony discusses. I also wish to state that his conclusions result from an examination and review that I led, that I consider to be sufficient to support those conclusions, and that I am prepared to address, should any party to these proceedings have any questions about the details of the work effort involved in undertaking this examination and review.

Q. Does this complete your testimony in these proceedings?

A. Yes.